Review of Utility Interconnection, Tariff and Contract Provisions for Distributed Generation

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A report to the NARUC Committee on Energy Resources and the Environment

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This paper is based on a report originally provided to the NARUC Staff Subcommittee on Energy Efficiency and Renewable Energy (ERE) by R.W. Beck, Inc., under a contract with the NARUC. Throughout the preparation process, the members of the NARUC Committee and Staff Subcommittee on Energy Resources and the Environment provided R.W. Beck, Inc. with editorial comments and suggestions. Subsequently, ERE members edited the report to create this final version. Written comments are encouraged.

Introduction

This report is submitted on behalf of the Staff Subcommittee on Efficiency and Renewable Energy (ERE). R. W. Beck and Distributed Utilities Associates worked under contract to NARUC to complete a study of model provisions for interconnecting distributed generation (DG) into utility grids. The focus of this effort was the application of DG within the traditional vertically integrated utility industry structure. Their approach was to gather standards and contract language from existing or developing sources, and modify it where needed. The initial report from R.W. Beck and Distributed Utility Associates was substantially edited by ERE members, in an attempt to make it more accessible to readers who are not already familiar with the subject matter.

Section 1 of the report discusses the background and proposed role for the model provisions. Section 2 covers proposed provisions for technical interconnection of DG. Section 3 covers non-technical provisions, contractual and procedural issues. Section 4 covers policy and related provisions. Section 5 presents a summary and discusses, for NARUC consideration, recommendations for additional steps that can be taken in order to continue progress on these important issues.

We greatly appreciate the work that was completed by the project team of R.W. Beck, Inc. and Distributed Utility Associates. Any errors in this report are the responsibility of the ERE Subcommittee members. Please direct comments and suggestions to John Emmitte of the NARUC staff:

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NARUC
REVIEW OF UTILITY INTERCONNECTION, TARIFF AND CONTRACT PROVISIONS FOR DISTRIBUTED GENERATION

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EXECUTIVE SUMMARY

As distributed generation technologies advance, existing utility interconnection requirements and regulatory processes associated with them are often too restrictive to allow the full capture of the potential benefits distributed generation (DG[1]) might provide. DG benefits have been widely discussed in the literature. They include better customer reliability, better distribution asset utilization, relief from transmission constraints, environmental benefits and others. Overly restrictive and non-standard interconnection requirements can -- intentionally or not -- form significant barriers to the implementation of otherwise cost-effective DG. As such, interconnection standards and guidelines are evolving and being addressed from technical, procedural and policy points of view.

This report reviews recent advances in interconnection standards and procedures and proposes a set of model technical, contract and policy provisions where possible. Where existing provisions have not been found, issues and parameters important to stakeholders are discussed. The focus of this report is the traditional, vertically integrated utility industry structure. These same issues will need to be addressed in the emerging world of customer choice and industry restructuring, too, but those topics are beyond the scope of this effort.

In addition to individual utility standards, three states have focused considerable effort on the development of standardized DG interconnections – Texas, New York, and California. The Public Utility Commission of Texas (PUC-TX) was concerned in late 1998 that there would be a capacity shortfall over the next two summers. It began an effort to develop a statewide, standardized interconnection agreement, with straightforward and clear procedures, to enable renewable energy systems and new and stand-by generators under 10 MW in size to interconnect. The Texas rule was adopted in November, 1999. The State of New York conducted a similar effort under the direction of the New York State Department of Public Service (NYDPS), starting in August 1998. Like Texas, the NYDPS divided this effort into technical and non-technical working sessions. The California Public Utility Commission (CPUC) is proceeding with an order instituting ratemaking (OIR) to examine, among other subjects, the appropriate role of DG and its relationship to the distribution utility. The topics being addressed in that proceeding cover several interconnection, technical and policy issues.

[1] DG is used in this report, interchangeably, as an abbreviation for either distributed generation or distributed generator. DGs means distributed generators. DG is a subset of technologies and practices known as Distributed Resources (DR), or sometimes Distributed Energy Resources (DER). In this report, the abbreviation DR is used. DR means technologies and practices for energy storage and demand management (called demand-side management, or DSM), in addition to DG.

This report describes the relationship among processes, standards and policies regarding DG and proposes a methodology for thinking about them. We believe that regulators need to address all of these three rubrics (interconnection, tariffs, and contracts) in combination; that working on any one or two of them in isolation will not be sufficient to result in the changes necessary to allow DG (in particular, and Distributed Resources, in general) to participate fully in electric utility markets.

The technical provisions proposed in this NARUC report do not comprise a complete technical standard. This report represents only one step in a complex, multi-party process to allow the beneficial interconnection of DG. Interested parties include regulators, utilities, customers, DG equipment vendors, suppliers and installers, and others who are stakeholders in the process.

The technical guidelines and standards recommended in this report are based primarily on the Texas DG guidelines developed in late 1998 and early 1999. The fundamental objective of the Texas effort was to propose a technical interconnection standard that, if implemented, would allow the DG to be integrated into the utility grid, quickly, safely, and ensuring continued reliability of electric power supply to all customers. The Texas guidelines were developed in a collaborative effort amongst DG vendors, Texas electric utilities, PUC-TX Staff, energy service providers, and other interested parties. During the time this NARUC report was being completed, the PUC-TX adopted its final DG interconnection rule, application, and standard contract. That set of documents addresses the bulk of the issues covered in this report. Since no other state public utility regulatory agency has taken final action on DG yet, readers are encouraged to review the Texas rules.[2]

This report introduces a series of proposed non-technical contract and tariff provisions intended to govern the relationship between a DG owner/operator and their distribution utility. We were not able to find an existing model contract that covered all of the important topics we identified. Those topics include utility distribution system studies and customer charges for completing them, liability insurance coverage, the application process for interconnecting, and other requirements. Usually, these kinds of provisions will be enacted by means of a set of rules or an interconnection contract or both.

The report covers policy implications for the interconnection of DG. Policy positions on DG have been taken by several states, the federal government, and industry working groups. Much of this policy material is focused on utility restructuring, but is still valuable to consider how it may apply to vertically integrated utilities.

In this report, the model utility interconnection tariff and contract provisions for DG are proposed as important preliminary steps towards removing barriers to the interconnection of beneficial DG. We believe that this NARUC report has

[2] See <http://www.puc.state.tx.us/rules/rulemake/21220/21220.cfm>.

helped to identify both technical and non-technical issues and topic areas that should be addressed in the course of DG policy making. The report sets forth a series of preliminary recommendations for DG policies, and recommends next steps for NARUC and the individual state regulatory commissions, with respect to DG. These include:

- Supporting accelerated development of IEEE SCC 21;
- Exploring methods for allocating the many specific system benefits of DG;
- Addressing the issue of wires company[3] use or ownership of DG;
- Exploring possible relationships and coordination between net metering and other DG policies and practices; and
- Supporting a broader industry effort, with expanded stakeholder participation, to address these kinds of DG policies and regulatory provisions.

[3] A "wires company" is a utility that provides local distribution services. In thinking about future structures of the electric utility industry, one widely discussed possibility is for separation into three types of companies: generation, transmission, and distribution. This is occurring in Texas, and in those states that are implementing retail electric competition. In some scenarios, wires companies would be involved only in local distribution and not transmission or generation. For the purpose of this paper, we define a wires company as a local distribution company that does not own any generation, except perhaps for DG in its own service territory.

SECTION 1
INTRODUCTION AND PROCESS

1.A INTRODUCTION

As electric power production technologies have advanced, several smaller-scale generation options (including micro-turbines, fuel cells, wind, solar and others) have shown increasing market appeal. However, it is generally recognized that significant regulatory and utility barriers may hamper these products from providing benefits both to customers and the utility grid. At its July 1998 summer meeting, NARUC passed a resolution that recognizes the benefits of smaller scale generation and supports reducing barriers to their entry into public electric utility markets. This report presents the results of an investigation of existing utility and state interconnection requirements and policies regarding distributed generation (DG). For this effort, the definition of DG is limited to generation to be installed on low-voltage distribution systems.[4]

This report describes three broad areas where interconnection requirements may present entry barriers to small-scale generation for customers.[5] These include:

1. Technical interconnection requirements for operation in parallel with the utility;
2. Non-technical interconnection contract terms (provisions and requirements such as hookup fees and liability insurance); and
3. Policy and institutional disincentives (such as those arising from tariff prices and provisions, or the regulatory requirements for interconnecting with the grid).

The primary focus of this project was to review and analyze existing standards and contract and tariff provisions, and then to develop a proposed set of interconnection provisions for DG. The suggested approach applies to vertically integrated, regulated monopoly utilities, and does not address the access and pricing issues for sales into a competitive power exchange. This study offers a set

[4] Generators connected to the transmission system will be regulated by FERC under existing standards and procedures for open access transmission.

[5] This paper focuses on systems that are installed on customer premises, and are interconnected on the customer's side of the electric meter. The customer or another party could own them. DG can also be installed by the utility, on the utility side of the meter, but many of the concerns discussed here would be less important or even inapplicable in that situation. Still, many of the same technical interconnection requirements will have to be addressed, regardless of variations in system ownership, control, relation to the meter, and grid location.

of model interconnection tariff provisions, for NARUC consideration and possible adoption by state utility regulators.

Distributed Generation and Restructuring

This report addresses vertically integrated utilities. Interconnection issues and approaches for a restructured electric utility industry are beyond the scope of this work. However, many of the technical standards and discussions in Sections 2 and 3 are valid for states with customer choice. Typical restructuring proposals include some version of a "wires company" -- a distribution services company -- that has the responsibility to maintain the safety and reliability of the distribution system. For better or worse, the electrical characteristics of the network will not change, regardless of how competitive the power supply business becomes. However, under restructuring and with significant numbers of DG installations, the characteristics and operations of the distribution network could evolve over time.

In a restructured electric utility industry, the contractual and other provisions in Section 3 will still remain applicable, to a great extent. The approaches needed for installation and safe operation under a customer choice regime will be similar because the Wires Company will continue to serve as a regulated utility. To the extent that metering and billing services turn out to be competitive, the proposals presented in Section 3 will need to be modified.

The interconnection policy recommendations in Section 4 are only partially compatible or consistent with restructuring. So far, restructuring proposals lack any clear definition of and directions for policy alternatives for DG interconnection. A few states are taking the lead, but are moving into largely unexplored policy territory.

The authors believe a substantial industry effort will be needed to allow -- technically, economically, and contractually -- the full capture and allocation of DG benefits under customer choice.

1.B PROCESS

The process employed was (1) to find the most equitable set of existing interconnection standards, contract and tariff provisions; (2) to utilize the reasonable provisions that were found; and (3) to adapt or modify provisions as required to more equitably handle DG, based on the project team's best judgement. Due to tight time constraints and the need to explore a large number of applicable utilities and states, the research team enlisted others to assist in data gathering. They developed a topic list and requested input from a core group of interested parties. Unfortunately, that request did not result in much input. They also conducted a survey of selected states and utilities.

The working principle for adapting or modifying provisions was to try to best balance network safety and system requirements with DG owners' needs for reasonable arrangements. For a few specific interconnection provisions, where no particular solution appeared adequately balanced, more than one potential solution is presented and discussed. This report presents the compiled provisions thus gathered, developed, and modified. Together, they form the Model Interconnection Tariff and Contract Provisions for Distributed Generation, offered for consideration by NARUC.

1.C THREE STATE EFFORTS REPRESENTED

Three states have been actively engaged in developing standardized procedures for DG interconnection – Texas, New York and California. The Public Utility Commission of Texas (PUC-TX) was concerned in late 1998 that there would be a capacity shortfall over the next two summers. It began an effort to develop a state-wide, standardized interconnection agreement. The intent was to provide straightforward procedures to enable small scale renewable energy and new and stand-by generators to interconnect in a safe and reliable manner. The PUC-TX established two industry working groups; one to discuss and develop a consensus approach to the hardware and technical issues, and a second to address policy, contracts, and tariff provisions. These working groups included broad representation from utilities, equipment suppliers and other interested individuals.

On February 4, 1999, the PUC-TX adopted interconnection guidelines for DG. The guidelines provide a starting point for negotiations between the owner of a generating unit and their local electric distribution company. Then, on November 18, 1999, the PUC-TX adopted a DG interconnection rule, along with standardized DG applications and interconnection agreements, for use by all Texas utilities.[6] The rule applies to all DG less than or equal to 10 MW in size. It spells out technical interconnection provisions, places time and processing requirements upon the utilities, for timely handling of DG interconnection applications, and limits the justifications why a DG interconnection request can be denied. The Texas rule and companion documents were developed in collaboration amongst Texas utilities and members of the national DG manufacturing, vendor, and energy service company communities. Many of the terms and conditions represent consensus among the parties. Now that the rule is completed, the PUC-TX will be working with interested parties to develop an interconnection manual, which standardizes the determination of DG costs, benefits, and distributed system impacts. The PUC will also develop a formal DG pre-certification program, for use in Texas and elsewhere. (Pre-certification is discussed briefly in this report. See section 2.B.7 Certification and Testing, p. 12.)

In NY State, the staff of the Department of Public Service (NYDPS) initiated, in August 1998, a collaborative process to standardize and streamline interconnection requirements for small generation up to 300 KVA on radial

[6] See <http://www.puc.state.tx.us/rules/rulemake/21220/21220.cfm>.

feeders.[7] Parties representing various stakeholders actively participated in many months of group discussions that took place separately for technical and non-technical issues. After several procedural steps, the PSC made its decision adopting interconnection requirements, in a December 31, 1999 order.[8]

The California Public Utility Commission (CPUC) is proceeding with an order instituting ratemaking (OIR), examining, among other things, the role of DG and its relationship to distribution utilities. The topics addressed there cover many interconnection, technical, and policy issues.[9]

1.D ROLE OF UNIT SIZE

Generator unit size is an important variable in considering interconnection standards and requirements. There is a substantial difference in impact between, for example, a 2 kW residential generator and a 1 MW industrial unit. This report notes where the type and size of generating units would make a difference to a proposed provision or contract term. However, each of the various information sources reviewed has its own definition of what sizes constitute small, intermediate, and large systems. Thus, this report does not provide a specific proposal for generator size groupings, but where unit size does make an important difference, the applicable size ranges are mentioned for the rule or provision discussed.

1.E PROPOSED ROLE OF MODEL INTERCONNECTION AND CONTRACT/TARIFF PROVISIONS

The ability to produce a universally accepted interconnection standard and interconnection contract is beyond the scope of this effort. Instead, this report provides (1) a "work-in-progress" interconnection guideline and (2) a set of potential contract provisions. The interconnection guideline is simpler than most existing utility standards because it is based on functions, rather than hardware. Still, we believe it does provide adequate safety and system protections. This functional approach was chosen because it provides the flexibility needed for

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[7] A "radial feeder" is an electric path that normally transfers energy in only one direction, from a source to one or more loads.

[8] The Commission Order of December 31, 1999 in Case 94-E-0952, Opinion 99-13, is available on the NYDPS web site, indexed under "PSC File Room–Data Base Search–Rulings", or by direct access to <http://www.dps.state.ny.us/fileroom/doc7024.pdf>. The Order discusses the details of the process, parties comments, and the decisions. See also <http://www.dps.state.ny.us/distgen.htm>. On July 19, 1999, the NYDPS Staff issued its report, New York State Standardized Interconnection Requirements, Application Process, and Contract for New Distributed Generators, 300 Kilovolt-Amperes or Less, Connected in Parallel with Radial Distribution Lines (SAPA No. 94-E-0952 SA18).

[9] See <http://www.cpuc.ca.gov/distgen/index.htm>.

implementing the large variety of different modern technologies. For the second part, existing interconnection contract provisions are discussed, and adapted where necessary, to provide the key model provisions that we believe represent the appropriate balance between the needs of utilities and small generators.

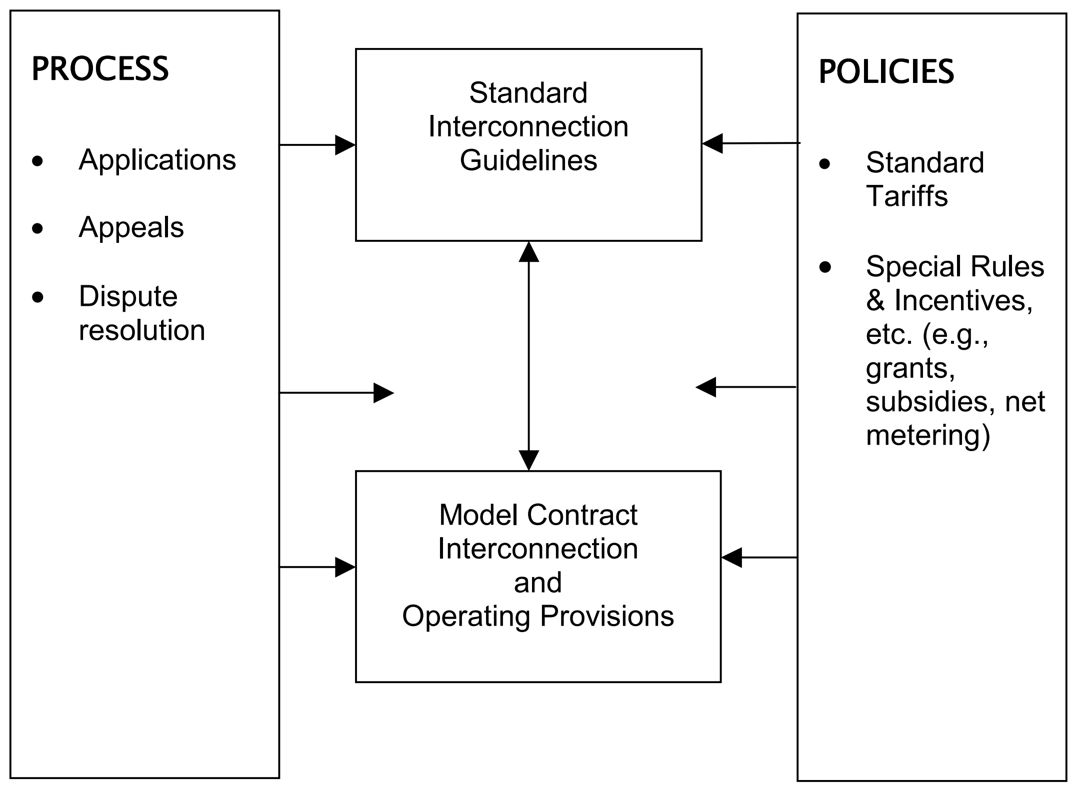
The proposed contract provisions represent a portion of a broader set of rules and requirements intended to direct interactions between the utility distribution provider and the small generator. As part of the effort to analyze contract provisions, two states' proposed DG application processes were reviewed. In this context, "processes" mean the set of application rules, timing requirements, appeals, and dispute resolution methods that apply to DG. Neither process addressed all the issues in a balanced manner, nor do we expect a single, standard process to work in all jurisdictions across the country. Here, several concepts are proposed, to address the major issues identified in this review.

Many states' rules, policies, and incentives for DG are also reviewed and summarized. These are viewed as adjuncts to specific tariff and contract provisions, rules and policies. Several Federal and State policies apply only some technologies, and not others.

Figure 1.1, next page, depicts the above discussion. The Standard Interconnection Guidelines and Model Contract Provisions are sandwiched between the policy on the right and the process procedure on the left. This format best indicates how to consider and utilize the information in this report.

Figure 1.1

Proposed Role
of
Model Interconnection and
Tariff Contract Provisions



SECTION 2
TECHNICAL INTERCONNECTION PROVISIONS

2.A INTRODUCTION

The scope of this report includes the review of existing technical interconnection standards for DG. Technical provisions mean the hardware specifications and operating procedures that relate directly to utility safety and system protection. Many of these standards were reviewed for appropriateness, fairness, and completeness, and the best of them were incorporated into a proposed model interconnection standard. A list is included of other model provisions that were considered but not incorporated into the model standard. There are a number of technical guidelines and standards that are being developed for DG, and information from them has been incorporated into this report. The format, for the most part, is based on the existing Texas DG Guidelines. These guidelines were developed by an industry workgroup in late 1998 and early 1999. This format was adopted for several reasons:

- The format covers many topics that are of concern to the Texas Public Utility Commission, electric utilities, equipment vendors, industrial groups, consumer groups, and other interested third parties.
- It establishes a fast approval process that does not require participants to submit excessive documentation, but it adequately emphasizes safety and system reliability.
- It is flexible, reflecting necessary limitations without prescribing exactly how they will be accomplished.

Several new standards for DG interconnection are also emerging from the IEEE Technical Standards groups. Once those standards are published, any standard produced using the information and recommendations provided in this report should be reviewed for consistency and completeness. In any case, it is not likely that the IEEE Technical Standard will fully replace all of the provisions discussed in this report, since this effort includes a wider range of topics compared to the anticipated IEEE Technical Standards.[10]

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[10] See <http://grouper.ieee.org/groups/scc21/1547/index.html>. The IEEE Standards Coordinating Committee 21 (SCC21) works on standards regarding fuel cells, photovoltaics, dispersed generation and energy storage. The SCC21 working group is presently estimating it will publish a draft of "P1547 – Standard for Distributed Resources Interconnected with Electric Power Systems" in the spring of 2001, and expects final publication as an IEEE standard by the end of 2001.

This document provides a model technical interconnection standard that, if implemented, can provide for the rapid, safe, and reliable incorporation of DG into the utility grid. Where various policy rather than technical issues must be resolved, this report includes discussions of options and their implications, *in Italics*.

2.B PROVISIONS FOR THE MODEL TARIFF

2.B.1 CLASSIFYING DG UNITS BY UNIT TYPE AND SIZE

The appropriate details of an interconnection with the utility grid vary in accordance with the type and size of distributed generating units. DG units should be classified according to the type of technology, fuel source, and power system interface. Common technologies include reciprocating engines, hydro-electric, wind, photovoltaic, solar thermal, geothermal, gas turbine, and fuel cells. Fuel sources are classified as fossil fuel, renewable, or electric storage. Each DG is either directly connected (electromechanical) or connected through an inverter. Direct connected devices are usually rotating machines that produce 60-hertz power. Inverters are usually connected to the output of a generator that produces DC electricity.[11]

The size of the unit is another deciding factor affecting appropriate interconnection. DG units can be classified as small, intermediate or large. Small units are less than 100 kW, intermediate are 100 kW to 1 MW, and large are greater than 1 MW.

The table on the next page, "Classifications of Common Distributed Generation Technologies," displays the various classifications. Most classification schemes use three levels: small, intermediate, and large. The important issue is not the specific dividing lines between each size, but that size itself is a useful framework for determining appropriate interconnection rules and practices. More work is needed to establish the most appropriate size classification scheme. The PUC-TX's adopted rule is exemplary in this regard. It applies to all DG units #10,000 kW (10 MW). It generally breaks DG units down by size as: (1) single phase, <50 kW; (2) 3-phase, <10 kW; (3) 3-phase, between 10 & 500 kW; (4) 3-phase, 500–2,000 kW; and (5) 3-phase, 2,000–10,000 kW. Under PUC-TX's interconnection rule, requirements for DG control, protection, and safety equipment intensify as DG unit size increases.

[11] Several different inverter technologies exist, but they can all be classified as one for purposes of this document. Readers should note, however, that some older inverter technologies might not be able to meet all modern requirements.

Table 2-1:
Classifications of Common Distributed Generation Technologies

Technology	Fuel Source	Interface	Small <100 kW	Intermediate 100 kW–1 MW	Large >1 MW
Small Gas Turbine	Fossil Fuel Renewable	Directly Connected			X
Reciprocating Engine with Synchronous or Induction Generators	Fossil Fuel Renewable	Directly Connected	X	X	X
Geothermal	Renewable	Directly Connected		X	X
Hydro	Renewable	Directly Connected		X	X
Wind	Renewable	Inverter	X	X	X
Photovoltaic	Renewable	Inverter	X	X	
Fuel Cell	Fossil Fuel, Renewable	Inverter	X	X	X
Solar Thermal	Renewable	Directly Connected	X	X	X
Battery Storage	Grid or DG	Inverter	X	X	X
Capacitor Storage	Grid or DG	Inverter	X	X	
Flywheel Storage	Grid or DG	Inverter		X	X
Superconducting Magnetic Energy Storage (SMES)	Grid or DG	Inverter		X	X
Microturbine	Fossil Fuel, Renewable	Inverter	X	X	

2.B.2 Safety Considerations

Safety is a critical issue for DG interconnection. The additional sources of generation pose potential safety hazards to electric utility workers, fire and rescue workers, and the public. This standard is intended to minimize the potential for such hazards.

DG safety and interconnection rules should be designed to assure that utility workers do not believe a conductor is de-energized when in fact DG is energizing it. Without proper standards and work practices, serious injury and even loss of life could occur.

Existing utility standards for DG interconnection are based on extensive experience with generation of various sizes and types. The standards are intended to be failsafe. They cannot be compromised under any circumstances.

Some flexibility in implementation is needed, however, to allow installation of new products and devices that meet all requirements, even though they may not meet a particular utility's historical practices and standards.

Safe operations can be established in many ways. Existing safety practices have been in place for many years, and are often based on requirements for large generators. In many cases they may exceed today's needs, especially for DG. Comparable or better levels of safety can be accomplished at a lower cost than by following many of the standards now in place. The standards proposed in this document are replacements for many of the practices and standards that electric utilities have used for many years in the implementation of large generation.

The following subsections address items that are of major concern for safety.

2.B.2.1 DE-ENERGIZED LINES

When the utility's power source (exclusive of DG) fails to provide energy to the system, the DG must be separated from the utility's load with the following exceptions:

Exception 1: In a DG system that is expressly designed for this purpose, specific loads that are served by DG, such as emergency or standby loads, shall be allowed to be energized.

Exception 2: Where the utility has engineered the electric distribution system to allow such energizing, the loads may be supplied exclusively from DG at times when the primary source of power fails.

2.B.2.2 ISOLATION FROM THE UTILITY SYSTEM

The DG shall be able to be isolated from the utility's distribution system. The means of physical isolation shall consist of the following:

- The means of physical isolation shall be able to completely isolate the DG from the electric utility system. This device may be located at the service entrance or somewhere between the generator and the service entrance. This device may be a disconnect switch, a draw-out breaker, a fuse block, or another commonly used means of physical isolation. These devices must be able to be controlled on-site and may also provide for remote control.

- The means of physical isolation must always be accessible to electric utility personnel (24 hours per day, every day). This can be accomplished by access to the facilities through a dedicated utility key lock or other means that will minimize delay in the utility's access. The physical isolation device must provide an indicator that the DG is isolated.

  Some existing requirements include a visible disconnect. Although often open to some interpretation, this typically means that a person can view the contact to ascertain whether it is open. This practice was put in place because early disconnect switches and breakers frequently failed to be open, despite having indicators showing that they were open. It is expected that modern technologies have an extremely low probability of this type of indicator failure. That, coupled with good work practices, should lower the probability of damage or injury due to such a failure to almost zero.

- The means for disconnecting shall provide for a complete, open circuit. The devices must be able to be controlled on-site and also remotely.

  Although physical disconnect is a requirement for all units, this can be accomplished by different means depending on the size of the unit and type of technology involved. The DG shall be able to be completely physically disconnected and isolated from the utility system. The disconnection device shall always be accessible to the distribution utility.

- The means for disconnection shall either provide for a visible disconnect or an indicator that identifies the status of the disconnect. If an indicator is used, it shall be failsafe, to ensure that when the indicator denotes that the circuit is open, it is assuredly open.

  Some requirements include the need for a redundant circuit breaker. This requirement should apply for major generation that is critical from a systems operations standpoint. This is a special concern that is discussed in 2.B.3.2 on Protection Requirements (p. 2-7) .

- For the purpose of assuring the safe operation of the electric distribution system, the owner/operator of the DG should follow the electric utility's safety procedures for the switching, clearance and tagging. For *intermediate* and large generators, both the generator and the utility will be responsible for ensuring that the switching, clearance and tagging procedures are followed. The distribution utility will provide complete information about its procedures to the owners and operators of DG in its service territory.

- For small generators, the distribution utility shall ensure its electric distribution and transmission system personnel follow designated switching, clearance and tagging procedures.

This tariff does not intend to conflict with National, State and Local Standards and Codes. Each entity is responsible for assuring that they meet National, State and Local standards and codes.

2.B.3 SYSTEM RELIABILITY

It is the responsibility of the generator/owner to operate within the system stability limits as defined herein. The major parameters that assure system reliability include voltage support, VAr support, frequency limits, power factor, and harmonics.

2.B.3.1 SYSTEM STABILITY REQUIREMENTS

- Voltage should be maintained within +5 to –10% from nominal voltage within a 10-second time frame.

  Other ranges are acceptable for this parameter, such as ± 10%. The Texas rules, for example, require an automatic disconnect if the variation from nominal voltage exceeds +5% or –10% for more than 30 seconds, or +10% or –30% for more than 10 cycles. Another methodology to consider is meeting the CBEMA curve. This curve establishes a limit of –15% for long-term voltage drops, but allows voltage excursions of up to –35% at 10 cycles and –75% at one cycle.

- For small generators, power factor shall be maintained within the range of ± 85%. In some instances, with joint agreement between the generator and distribution utility, the power factor range can be expanded. For intermediate and large generators, the power factor must be maintained within some specified range, which is yet to be determined. In addition, the local voltage must be supported, to avoid excessive voltage fluctuations.

- When operated in parallel with the utility distribution system and whenever the generator is serving equipment that is also served by the utility distribution system and not owned by the generator owner, the frequency shall be held to 60 Hertz.

  The Texas rule requires systems to disconnect within 15 cycles any time frequency varies more than +0.5 Hz or –0.7 Hz from the 60 Hz base.

  When a DG system is not operating in parallel with the utility system and not serving loads outside the host facility, this is a recommended practice; not a requirement.

- The source of electric energy shall not produce any harmonics in excess of what is allowed by Standard IEEE 519.

  For small and intermediate DG, the distribution utility shall employ means necessary to mitigate harmonic effects.

  For large generation sources, if the DG meets IEEE 519, the distribution utility is responsible for providing the appropriate modification to the distribution system. *(If a DG that meets IEEE 519 is installed but system harmonic levels are excessive, then other sources must be contributing to the problem.)*

Harmonics may have an effect on the electric system, whether the source is large or small. Sources of harmonics include most loads, transformers, voltage regulators, etc. Generators and inverters may also be sources of harmonics. IEEE 519 provides guidelines for harmonics, based on load needs.

2.B.3.2 PROTECTION REQUIREMENTS

Protection requirements will differ based on the size and type of DG as well as its integration into the distribution system. The protection standards identified in the following paragraphs are for the safety of electric utility workers and the public. These standards are not intended to protect the DG equipment itself, nor the generator's facilities.

The protection requirements shall be defined as follows:

- Minimal Protection: All generation systems must provide: overcurrent protection and protection for circuits with reclosing.
- Inverters: Inverters shall be designed to shut down upon the detection or indication of a short circuit, and/or separation from the utility circuit. If such circuitry is not incorporated in the inverter's design, the inverters shall have the same protection equipment as similar size direct-connected units.
- Direct Connects (for small generators with no inverters): The protection system shall be designed to ascertain that the generator isolates itself from the utility system when: (a) A short circuit occurs where the generator contributes fault current, in which case the DG shall be disconnected from the distribution system in a manner that is coordinated with the other protective devices associated with the distribution system; or (b) The generator is separated from the source of utility generation and is providing voltage to part of the utility's electric distribution system, in which case the DG shall immediately separate itself from the electric utility distribution system. Systems to provide the above functions may include overcurrent protection, reverse overcurrent protection, reverse power protection, over- or under-voltage protection, frequency protection, or transfer trip protection.

  More detailed studies can provide information that could be used to limit the amount and types of protection needed. See the discussion on system studies, in section 3.B.1.
- Direct Connects (for intermediate and large generators with no inverters): When a short circuit occurs where the generator contributes fault current, it shall be disconnected from the distribution system in a manner that is coordinated with the other protective devices associated with the distribution system. When the generator is separated from the source of utility generation and is providing voltage to part of the utility's electric distribution system, it shall immediately separate itself from the electric utility distribution system.

Due to the larger effect on the distribution system, some intermediate and all large disconnect systems require more positive action to ensure tripping. Additional relay protection typically requires overcurrent protection, reverse overcurrent protection, reverse power protection, over/under voltage protection, frequency protection, or transfer trip protection.

In some cases, the addition of DG leads to the need for protective device coordination that is different from that needed under circumstances when no DG is present. In a worst case situation, a lack of coordination when distribution system fuses blow could damage utility equipment and cause outages. The source of generation shall be protected so that it does not unduly contribute to the short circuit current and timing. The DG protective devices shall be coordinated with other protective devices for the same circuit, to eliminate the source of generation from contributing to a short circuit. The DG protective devices shall react at the same speed or faster than other protective devices for the same circuit.

- Circuits with reclosing schemes: Where a distribution circuit with a reclosing scheme is used, the generator protection shall be coordinated so that the DG is disconnected from the utility distribution system before the breaker or switch is reclosed. If the reclosing scheme provides for an instantaneous trip with one or more reclosures, the generator shall trip off instantaneously upon sensing a short circuit or other event that would have tripped off the reclosing scheme. If the reclosing scheme provides for a timed trip, the generator shall trip off line within a time period coordinated with that of the recloser. If the DG is connected to the power system via an inverter, the inverter needs to be shut down according to the above rules.

  Once sufficient time has passed for all breaker reclosing schemes to perform their operations, the DG may resynchronize with the power system. Under no circumstances shall the DG connect to a de-energized distribution utility conductor unless that operation is specifically approved and takes place under the guidance of the distribution utility.

- Synchronizing: Every DG that provides a synchronous source of interconnected power shall be connected using a synchronizing scheme. The synchronizing scheme employed shall ensure that the DG is connected substantially in phase with the power system. Under no circumstances shall the system be synchronized at a greater than 15 degree difference in phase angle. Inverters shall have circuitry to assure that power is not delivered until the phase angles are substantially in phase.

- Islanding: When one or several DGs are separated from the utility source of energy, the system is islanded and the DG(s) shall be isolated from the remainder of the distribution utility's load. The DG owner's load may be connected to the DG as long as the DG is not energizing any conductor outside of the DG owner's facilities or location.

Care must be taken to ensure that inadvertent or unwanted islanding does not occur. This is critical, due to the potential for safety, voltage, or frequency problems, etc. In some cases, a study may determine that islanding is advantageous to the local utility. In these circumstances, the utility may opt to allow islanding under certain circumstances.

The operation, protection, maintenance, etc., of the DG equipment shall be completely and exclusively the responsibility of the DG owner. The interconnection of DG into a utility distribution system requires both protection equipment and operating procedures that ensure the generator will be self-protecting. These standards do not address the protection of the DG equipment, itself.

Protective equipment must ensure that the voltage produced by the DG stays within ± 10% of the rated voltage, under all circumstances. If the voltage strays outside these limits, the DG shall be tripped off-line to isolate the distribution system from the DG.

Resonant over-voltages can cause serious damage to equipment and cables. The distribution system and connected DG can be treated as a solidly grounded or a low-impedance grounded system. If so, the system must remain solidly grounded under all circumstances, including during any switching or disconnecting that would potentially leave the generator operating in an ungrounded state. The only acceptable alternative is for the system to incorporate adequate resonant over-voltage protection.

The addition of DG may create an increase in the distribution system's total harmonic distortion (THD). The individual DG shall meet IEEE standards for harmonics. In some cases, the addition of generators (or loads) can lead to harmonics greater than those allowed by IEEE 519, even though each generator (or load), by itself, does meet the IEEE standards. Harmonic filters or other means shall be applied to keep total harmonic distortion within IEEE 519 limits.

All inverter technologies may inject some DC current into the AC distribution system. The amount of DC current that is injected into the power distribution system shall be #0.5% per inverter.

Isolation transformers are not a general requirement. However, isolation transformers may provide an alternative method to mitigate effects of ground fault current contributions and harmonics. Harmonics can be mitigated as discussed in the harmonics section. Ground fault (also called "zero sequence") current is not an issue as long as proper protection is provided.

The effect that a DG has on the electric distribution system depends on the number of DGs on the system and its stiffness before the DG is installed. The more short-circuit MVA available, the stiffer the circuit. The stiffer the system, the less effect a single DG will have on it.

The system stiffness ratio or short circuit ratio shall be used to determine the need for additional study. This ratio (from the IEEE P1547 Draft Standard for Distributed Resources Interconnected with Electric Power Systems) is defined as:

Short Circuit Ratio = (Short Circuit KVA of Utility Grid + Short Circuit KVA of Distributed Resource) / (Short Circuit KVA of Distributed Resource)

If the short circuit ratio is 100 or greater, the DG shall employ the minimal requirements for its size. If the short circuit ratio is between 50 and 100, additional study may be required to determine necessary protective systems. If the short circuit ratio is less than 50, extensive study efforts are required.

The PUC-TX DG interconnection rule requires that any pre-interconnection studies performed for a new DG installation must be completed within 4 weeks of the DG application date if the DG's load does not cause total DG on the affected distribution feeder to exceed 25 percent of its load. If the addition of the incremental DG unit would cause total DG on the affected feeder to exceed 25 percent of that local network's total load, then the utility may take up to 6 weeks to perform needed interconnect and network studies. Such studies may be performed by a qualified third party. The cost of the study must be estimated, and that estimate provided to the DG applicant, before the study begins.

2.B.4 POWER SYSTEM INTERFACE

DG may be capable of operating in parallel with the power system. This document assumes there will be at least some times when the DG operates in parallel. Some areas of this document pertain to operation in an open transition system; however, many limitations needed to operate in parallel do not apply to an open transition system.

The DG shall be a stable source of generation that can consistently maintain a set degree of power flow for a reasonable period of time. The DG shall maintain a stable VAr supply and voltage support.

If the DG is to be operated in parallel, it must be able to synchronize with the electric utility power system, so that it operates not more than 15 degrees out of synchronization with the power system.

Any time the DG has separated from the power distribution system, it shall not be put back into parallel operation until full voltage and power support capabilities for the distribution system have been reestablished.

It is recommended that the DG shall operate in a stable manner for 1 to 5 minutes before it is resynchronized with the system.

If DG is connected into a networked distribution system, there are special considerations that need to be taken into account. In most cases this would require changing both the interconnecting line and network protective relays. Special protective measures will be needed. Voltage regulators shall maintain levels within +5% and –10% of the rated voltage, as tested when the generator is not operating in parallel. When the generator is operating in parallel, the voltage regulator shall be capable of providing VArs to the distribution system according to one of the following plans:

- Constant VAr Source
- Constant Power Factor Source
- Constant Voltage Source

2.B.5 CONTROL & MONITORING SYSTEMS

2.B.5.1 GENERAL

The DG owner or operator shall maintain generation control. Generation control shall take into account coordination with the utility, including system protection and operating concerns.

DG may be automatically controlled, either locally or remotely. The controls shall allow for quick shutdown in the event that the level of generation or frequency varies outside established parameters.

Generation control can operate in one of two modes. In the first mode, the DG continuously supplies its maximum output. This is the most common mode of DG operation. In this mode, as long as all power quality parameters are being met, the DG will continue to operate.

In the second mode, generation is variable, or load following. In some cases, the DG maintains a set proportion of a customer's generation needs. The controls may be manual or automated, and may be operated from a remote location.

2.B.5.2 METERING, TELEMETRY, & COMMUNICATIONS REQUIREMENTS

Metering, in general, shall track the kWh production of the generation source. Additional metering may be required (such as kW demand, kvar, or kVA). Metering shall meet accuracy standards required for equivalent electrical services. Standard meters may be used, or any other electronic measuring devices that can be shown to meet data collection and accuracy requirements.

In specific circumstances, a single meter can be used in net metering mode. Otherwise, each DG will have its own meter.

Telemetry may be required to monitor real-time output and other DG functions, but is not required for small DG. For intermediate DG, telemetry is required if the generator is operated remotely, in variable output mode. Large generators require telemetry if operated remotely.

Telemetry data, where collected, shall be made available to the host distribution utility. Communications systems for telemetry and metering shall be compatible with the host distribution utility, where required. Data telemetered shall include generation data. This data shall include, at a minimum, the total kW or ampere level per phase. The minimum polling rate frequency must be determined.

Many different means of providing DG system communications are available, including SCADA, Automated Meter Reading (AMR), wired, wireless, and Internet communication channels. Any means that provides the required telemetry data to the host distribution utility is acceptable.

2.B.6 DATA REQUIREMENTS

Data may be required both to record transactions and to insure ongoing, safe and reliable DG operation. The data requirements may be classified as real time, summary, and failure reporting.

Real time data requires telemetry, as discussed in 2.B.5.2. It may be needed to report operating parameters (such as kW) for some intermediate and large units.

Summary data (a generator operations log) shall be produced for intermediate and large units. At a minimum, the log shall include the date, generator time on, generator time off, and megawatt (MW) and megavar (MVAr) output.

Several utilities require extensive generator operations data, including reports of failures and corrective actions. At least one utility requires an event recorder.

2.B.7 CERTIFICATION AND TESTING

The DG owner/operator shall provide to the host distribution utility the following minimal documentation and test results:

- One-Line Diagram – The diagram shall include at a minimum all major electrical equipment that is pertinent for understanding the normal and contingency operation of the DG system including generators, switches, circuit breakers, fuses, protective relays, and instrument transformers. The diagram should include transformer connections where applicable. A standard one-line diagram can be submitted for small and intermediate units that will be installed in multiple locations using the same system design. System-specific one-line diagrams shall be required for each large unit.

- Testing Records - Testing of protection systems for intermediate and large units shall be limited to records of compliance with standard acceptance procedures (as defined by the manufacturer of the protective devices) and by industry standards and practices. These records shall include testing at the start of commercial operation and periodic testing thereafter. Factory testing of protective systems of small units shall be sufficient, unless the factory test acceptance procedure specifies field testing of the unit or if a transfer trip is part of the protection equipment.

For packaged DG equipment, where the protective devices (including necessary relay settings) are part of a manufactured assembly that has been certified for use by the utility, the testing records need to be submitted only once. Each subsequent installation of the same manufactured assembly shall be deemed pre-certified for use by the utility.

The host distribution utility has the option to initially qualify a potential generator as a viable source of capacity and energy before signing a contract for resources. In order to assure the reliable operation of this generation they have the right to evaluate maintenance records, operating personnel, and capability of the generator as part of the contracting process. Equipment that may be reviewed includes the DG source and interface equipment such as disconnect switches, switchgear, and protection systems.

2.B.8 APPROVALS

The host distribution utility and the DG provider both have responsibilities for successful DG operation at each site. In order to facilitate DG implementation, a consistent and timely approval process is needed. The approval process will assure that the host distribution utility agrees that the applicant's DG implementation will not unduly affect the distribution (and in some cases transmission) system. The approval process shall also occur in a timely manner, to facilitate DG projects.

The Texas DG rule establishes firm time requirements for utility processing and approval of DG applications. Applications for DG interconnection must be processed in a non-discriminatory manner, in the order received. The rule requires that approval and interconnection should occur within 4 weeks of receipt of the completed application for DG installations that use pre-certified equipment, and 6 weeks for non-pre-certified equipment.

2.B.8.1 APPROVAL PROCESS AND DATA REQUIREMENTS

For intermediate and large DG units the following data shall be supplied from the DG to the host distribution utility:

Equipment specifications of major equipment including generator and protection systems including the following:

- One-Line Diagram
- System Protection Data
- Generator Operating Characteristics
- Location on Utility System
- Test Data
- Synchronizing Method

- Maintenance Schedules
- Data needed to coordinate the installation with that of the host utility.
- Anticipated Start Up date

For small DG, there shall be a once-only evaluation of the technology by an independent laboratory. Once the technology is approved, it shall require no further utility review. The results of the independent laboratory analysis shall be made available to the host distribution utility. The only submittal for approval for a small generator is the DG location (provided in a common format, such as street address), and anticipated startup date.

When reviewing particular proposals or equipment, the utility shall take into account the intent of safety standards and practices to insure reliability, and the ability of the proposed installation to meet that intent. The review should also take into account approvals of the same equipment by other utilities across the U.S. The utility shall explain any application rejections, citing the specific areas of non-conformance to utility standards and practices and negative affects on safety and reliability.

The Texas rule allows a utility to reject a DG application only if it can demonstrate specific reliability or safety reasons against interconnecting the DG unit at the requested site. Prior to rejecting an application, the utility must make reasonable efforts to work with the applicant to resolve any problems and effect a safe, reliable interconnection that allows the DG unit to export into the grid.

2.B.8.2 TIMING

The host distribution utility shall approve DG applications according to the following timetable:

Size of Unit	Maximum Approval (Calendar Weeks)
Small	1
Intermediate	4
Large	8

This schedule applies to complete DG applications. Delays may occur due to missing information. If the host distribution utility rejects an application, it shall give a full explanation of the reasons. Applications that are initially rejected can be resubmitted at any time in the future, after deficiencies are corrected. Applicants who wish to appeal a rejection should be afforded a means to do so, within a reasonable length of time (30 days, for example). The Commission might review rejected applications itself, or establish a forum and procedure for dispute resolution.

SECTION 3
OTHER NON-TECHNICAL CONTRACT PROVISIONS AND APPLICATION PROCESSES

3.A INTRODUCTION

A series of non-technical contract or tariff provisions govern the relationship between a DG owner/operator and the distribution utility. These provisions are typically embodied in (1) an interconnection contract or tariff that covers the installation, operation, and maintenance of a generating unit, and (2) a set of rules and procedures governing that contract.

This section addresses both contract non-technical requirements and application procedures. It includes a series of contract or tariff provisions that balance the needs of the utility system and DG owners. These provide the basis for an installation and operating agreement. In addition, it discusses interconnection application processes.

This section does not cover sales of DG output to utilities or into competitive markets. Those issues are reviewed in Section 4.

3.B INSTALLATION/OPERATING CONTRACT PROVISIONS

A model contract should provide equitable arrangements for all aspects of installation and operating arrangements between DG owners and the utility. The following suggestions are intended to cover contractual provisions for large DG installations. The complexity and number of provisions to be applied should vary according to DG system size, with simple contracts and applications used for small DG.

3.B.1 STUDIES AND FEES

To meet technical requirements for safety, system coordination, and protection in interconnection and parallel operation, the utility may wish to conduct technical studies. The need for these studies is reviewed in Section 2, which also discusses auxiliary hardware that could be needed for grid protection. This section addresses who pays for the studies and any required additional equipment. As discussed in Section 2, many small and intermediate sized generators can safely be installed without extensive studies and auxiliary hardware. A related topic is hook-up fees. In order to prevent market distortions, they should be cost-based and not arbitrary.

The major question is who should pay for studies and additions when deemed necessary; the generator or the utility? There are at least two opposing perspectives on this question. First, under FERC Open Access Pro Forma rules governing transmission, a new generator is generally required to pay for a system impact study and any required new lines, facilities and protection equipment. Similarly, some believe DG owners should be solely responsible for impact studies, and (at least in some instances) any new equipment required for continued, proper utility system operation. A second, alternative viewpoint is that DG is not markedly different from any load that a utility serves. In most utility rate structures, a portion of the cost required to connect any new customer's load is already incorporated in charges assigned to all customers, by class. Using this logic, the utility should pay for interconnection studies and facilities up to some threshold level, and the DG owner would be responsible only for incremental costs. To make this cost sharing approach fair to all customers, rates must be structured so that DG customers who meet most or all of their own energy needs cannot avoid paying their fair share of distribution service charges. That principle should apply both in the current regulated monopoly utility structure, and under restructuring. The Texas guidelines (February, 1999) summarized these different views as follows:

> "Utilities stated that each distributed generation supplier must pay the utility for the necessary distribution system upgrade. The opposing position is that the utility costs for the upgrades should be included into the overall capacity acquisition of distributed generation supply, and borne by the utility under a program that incorporates appropriate pricing of supply."

Utility regulators can play a key role in evaluating and subsequently supporting this second viewpoint. We believe the benefits to the distribution system of DG can be framed in light of utility regulatory policy. Those benefits provide a strong rationale for a blended cost structure. This could apply to both bundled and unbundled rates.

The Texas rule limits the need for DG interconnection studies, and assigns the cost to the DG applicant in cases where a study fee is permitted. Texas is now preparing a DG interconnection manual that will detail how such studies should be performed in the limited time available between the receipt of a DG application and the interconnection deadline, 4 to 6 weeks later. The studies are to examine both "costs incurred and benefits realized as a result of the interconnection… ." In establishing its final rule on DG interconnection, the PUC-TX stated, "The question of who bears the costs incurred to interconnect… new [DG] customers has not been resolved."

3.B.2 LIABILITY AND INSURANCE COVERAGE

It is a logical, reasonable expectation for DG owners to carry adequate insurance coverage. Electric generation can be a cause of damage to other equipment, personal injury and even death.

Working groups in Texas and New York addressed insurance issues. The Texas working group concluded that business and industry probably already have sufficient liability coverage for most DG installations in their facilities, but also noted that residential customers might have difficulty securing adequate DG insurance, if requirements exceed normal homeowner policy provisions. Excessive insurance requirements for residential and other small scale DG could prove to be a significant barrier. This affect would be most troublesome for wind, photovoltaic, and fuel cell systems.

3.B.3 INDEMNIFICATION

Part of the arrangement between the distribution utility and large DG owner is risk sharing between the two parties for third party claims. An ideal arrangement would balance risk in proportion to causation.

3.B.4 PERMITTING AND SITING

Permitting and siting issues for DG include: (a) environmental permits, (b) construction codes and local ordinances such as fire codes and zoning requirements, and (c) regulatory requirements, if any, for certification of public convenience and necessity (CPCN).

This report does not cover the first of those two items, but we note that different CPCN policies can significantly affect utility ownership and installation of DG. Further, a significant added market barrier exists wherever regulatory policies prohibit distribution utilities from installing DG themselves, or purchasing DG output from others.[12]

3.B.5 OTHER REQUIREMENTS

The technical requirements for operations are covered in Section 2. This section addresses the make-up of the contract or agreement between a large-DG owner and the distribution utility. A series of issues would be covered there, which might include the following:

[12] These topics are discussed in the NARUC companion report to this one, from the Regulatory Assistance Project, entitled *Profits and Progress Through Distributed Generation*, <http://www.rapmaine.org/distribution.html>.

- Compliance with technical standard
- Allowing the utility on-site inspections
- The handling of costs associated with interconnection
- Obligation of both parties to cure adverse effects
- Access rules
- Dispute resolution

3.C APPLICATION PROCESSES

The application process is the series of prescribed steps to be taken by a prospective DG owner/operator who desires to operate in parallel with the distribution utility. The utility requires information such as location, technical and design parameters, and operational and maintenance procedures. This is a process where simpler is better: It should be clear, concise and not burdensome on any party. No existing application process reviewed for this project meets all of these goals, but some of their specific components should be considered.

3.C.1 ESTABLISHMENT OF UTILITY CONTACT PERSON

To avoid confusion for applicants, the Texas PUC requested that staff "establish a process to identify the person at each utility responsible for interconnection of distributed generation." Texas also requires utility reports on requests.

3.C.2 APPLICATION FORM

The role of the application form will vary depending upon the size and perhaps the complexity of each DG installation. A small residential or commercial DG system, using standard, pre-approved equipment would need no more than a brief application providing basic information and establishing standard terms and conditions. The application and contract form could even be combined. Such a form might contain:

- Name of owner (and customer, if not the owner)
- Location on distribution system (address, and account number for existing customers)
- Interconnection voltage
- Type of unit (basic system and fuel type, manufacturer, and model number)
- Expected duty cycle or mode of operation
- Size of unit (kW)

- Name of qualified installer (with license number or other certification)
- Terms and Conditions of service

With this information, the utility can verify the equipment and its proposed location on the system, and assure it is not in a problem area. For example, too much generation at a particular location on the distribution network could be problematic.

3.C.3 APPROVALS AND INSPECTIONS

Some approvals and inspections are necessary, but should be calibrated to the size and complexity of each DG installation. Any unnecessary steps and procedures would be counter-productive. Practices should minimize the burden on both the DG owner and the utility.

SECTION 4
POLICY AND TARIFF PROVISIONS

4.A. INTRODUCTION

Policy positions on interconnected DG have already been taken by several states and are being developed in others. Further, DG is a special emphasis in some of the proposed federal electric utility restructuring policies, including the current administration's version. This section of the report describes important policy issues for a model interconnection tariff, and identifies the specific types of rulings to be considered by NARUC and the individual state PUCs.

The policy issues discussed here are drawn primarily from recent DG policy development efforts in Texas and California. The section begins with a general overview of policies adopted by Texas (in final rules adopted in December, 1999) and California (as reported by the California Alliance for Distributed Energy Resources Collaborative Report and Action Agenda, January, 1998). Those general overviews are followed by discussion of a litany of specific policy issues that have been raised in ongoing DG proceedings in California.

4.B. MODEL POLICY PROVISIONS

4.B.1 TEXAS PUC

The PUC-TX developed standardized, state-wide rules, applications, and contracts for DG interconnection, to remove the institutional barriers to DG use and allow Texas electric customers more supply options and choices.[13] The PUC-TX also wants to assure that existing customer-owned back-up generation and new, efficient DG can be used as alternatives to utility and independent power producer owned generation, to meet peak and routine energy needs in Texas. Texas began wholesale electric competition in 1995 and will start full retail competition in 2002. Now that its DG interconnection rules are in place, the PUC-TX will be developing an interconnection manual (to assure clear, unambiguous interpretation of the DG rules and study requirements) and a pre-certification mechanism to expedite "plug-and-play" DG market penetration in Texas. The rules are designed to reduce transactional barriers by establishing standardized:

- Pricing for T&D (loads pay) and tariffs for back-up power;

[13] See: http://www.puc.state.tx.us/rules/rulemake/21220/21220.cfm

- Interconnection Applications and Agreements;
- Pre-certification for DG equipment, where practical;
- Procedures and deadlines for utility processing of DG applications, studies, and associated fees; and
- Performance contracts between DG's and utilities.

Important features of Texas Senate Bill 7 (signed by Governor Bush on June 26, 1999) and the new Texas DG rules include:

- All customers are "entitled access to providers of distributed resources" effective September, 1999.
- DG use will not result in a responsibility to pay stranded cost charges.
- Structural unbundling, including the provision that transmission-dependent utilities (TDU's) and retail electricity providers (REP's) can not own generation.
- DG's may be owned by customers, energy service companies, and power generation companies, but not TDU's.
- DG's can sell output at wholesale to any utility but not other end-users.
- DG's can sell output at retail to end-use customers, energy service companies, retail electric providers, and power generation companies.
- Prices for DG power will be set by bilaterally negotiated contracts.
- DG prices will not be subject to avoided cost determinations, power exchange or pool pricing, or net metering.
- DG's are defined as 10 MW or smaller.
- The transmission and distribution systems will provide comparable open access to all sources of generation.
- Renewable energy systems that are customer-owned that do not export electricity to the grid are considered to be energy efficiency measures.

4.B.2 CALIFORNIA ALLIANCE FOR DISTRIBUTED ENERGY RESOURCES

The California Alliance for Distributed Energy Resources (CADER) is a non-profit, voluntary collaborative organization "committed to facilitating the successful deployment of highly efficient and environmentally responsible distributed energy resources into competitive energy markets." [14] CADER members include customers, energy service companies and consultants, DG

[14] CADER mission statement. See CADER Collaborative Report and Action Agenda (January, 1998). Copies available from CADER, c/o Mr. Pat McLafferty, 926 J Street Suite 1500, Sacramento CA 95814. Send check for $10, payable to CADER, Inc. For more information, see <http://www.cader.org>.

manufacturers and suppliers, representatives of local, state, and federal government agencies, and utilities. Two key premises underlie CADER's distributed resources (DR) policy positions. The first is that existing, emerging, and advanced DR technologies can and will be economically competitive for distributed energy and power applications. The second is that DR provides an array of benefits. Furthermore, CADER sponsors and participants appear to presume, in general, that to reap the many benefits associated with DR use will require new types of relationships between several key stakeholders, and there is a growing need for updated rules and regulations that do not pose unnecessary impediments to DR.

One example of an impediment CADER seeks to address is uncertainty about regulatory approval or permitting. An important way to reduce such uncertainty (and simultaneously to address other impediments to appropriate DR use) is to standardize economic valuation techniques, engineering models, regulations, and rules addressing DR. More specifically, to eliminate many unnecessary or outdated institutional biases and regulatory impediments to the use of otherwise cost-effective DR, CADER identified needs to coordinate among, update, reconcile, and standardize:

- community planning processes and criteria;
- building, fire, and safety codes;
- local siting and land use permitting processes and evaluation criteria, possibly including pre-certification of specific DR;
- environmental rules and regulations, especially air emissions permitting;
- design criteria and tools used by residential and commercial developers;
- electricity market price information forms, flows, and availability (especially historical, real-time, and projected electricity prices including those for transmission and distribution; ideally including prices that are location or area-specific);
- utility standby and backup rates and competitive transition charges (CTCs) associated with electric utility industry restructuring; and
- accounting, where possible, for societal benefits of DR use (such as fuel diversity, energy security, and reduced pollution) that are not easily internalized given present or expected electricity pricing mechanisms.

4.B.3 CALIFORNIA "WORK-IN-PROGRESS"

Motivated in large part by the advent of cost effective DR technologies and input from CADER, the California Public Utilities Commission (CPUC) initiated formal proceedings to evaluate DR business rules for the future.[15] The CPUC issued an order initiating rulemaking (OIR), stating, "The objective is to develop policies and rules regarding the deployment of distributed generation, such as interconnection standards, and rules for participation in these new markets."

The purpose of the CPUC order instituting ratemaking (OIR) is to investigate, through a collaborative process, whether and in what manner the CPUC should reform the structure and regulatory framework governing electric distribution service. The CPUC views the OIR as a venue to address the future vision of the electric industry and the appropriate roles of DG and local distribution companies. Topics to be addressed by the OIR cover the gamut of business, regulatory, operational and technical issues that result from fostering increased competition and DG market penetration.

Five California investor-owned utilities responded to the OIR with official filings: Pacific Gas & Electric Co. (PG&E); Southern California Edison Co. (SCE); San Diego Gas & Electric Co. (SDG&E) and Southern California Gas Company (SoCalGas) jointly; and Sierra Pacific Power Co. (SPP). The following summary discussion is not exhaustive, but illustrates many of the important positions utilities have expressed in their OIR filings. These positions are not suggested policies or recommended approaches, but rather, information on utility positions.

4.B.3.1 BENEFITS OF DG

Utilities generally believe they can, and should, evaluate and install DG where least-cost planning dictates it is the desirable option, meeting their performance based regulation (PBR) and customer reliability goals. The utilities seek CPUC assurance of "reasonable cost recovery when utilities use distributed generation cost-effectively in lieu of distribution expansion"(PG&E). The utilities say that customers have had, and should continue to have, the ability to install DG on their side of the meter and to capture the resultant cost, power quality and reliability benefits, as long as customers who do not have DG are not negatively impacted. SDG&E and SoCalGas note that increased customer DG may free up utility system capacity that can then be utilized for load growth and to provide standby services. In general, the utilities do not mention any quantifiable system benefits that will result from DG penetration on the customer side; nor do they suggest DG owners should be compensated for providing system benefits.

4.B.3.2 PLANNING

It is not clear how distribution system planning will be accomplished in the restructured utility industry, who will be responsible for it, and how least-cost planning can or will be employed in the context of a competitive electric market.

[15] See <http://www.cpuc.ca.gov/distgen/index.htm>. The CA-PUC October 21, 1999, Order Initiating Rulemaking (R. 99-10-025) is available in the documents section of the web site, at <http://www.cpuc.ca.gov/distgen/docs.htm>.

One fundamental question not raised by the utilities in their OIR filings is whether local distribution companies should be allowed to own any generation at all, including DG. The utilities raise many important questions that need to be addressed in DG policy formulation, such as: What methods will be used to evaluate DG vs. other distribution capacity alternatives? Will peaking, baseload or load following units predominate, and how will their operation be coordinated with the grid? What level of capacity assurance should distribution planners use to prevent either over- or under-capacity of the distribution circuit? What will be the rules for backup service? Who will control the ancillary services market and will DGs be required to participate, especially for local needs? Is there a critical unit size of a DG relative to the distribution circuitry used to supply it, such that an unexpected outage would threaten the integrity of the system? Utilities note that different planning and operational problems arise, depending on the location of DG; whether close to the substation or farther out on the circuit.

4.B.3.3 STRANDED ASSETS

The utilities view customer-sited DG as necessarily causing bypass of the distribution system to at least some extent, resulting in the stranding of distribution assets both at the substation and the distribution feeder levels. Utilities request reasonable cost recovery by the Commission if that occurs. SDG&E and SoCal Gas anticipate, however, "that overall system load growth may outpace any load loss resulting from distributed generation" resulting in "insignificant" stranded assets.

4.B.3.4 REGULATORY TREATMENT OF DG

The utilities feel that DG can be addressed adequately in the present regulatory structure. PG&E's concern is that "DG should not be artificially subsidized," and the Commission should be mindful of the "true costs" to all parties of implementing DG. They indicate that customer DG will generally lie outside the Commission's regulatory jurisdiction, except where the utility provides standby service or the customer wishes to back-feed into the grid. PG&E proposes that the latter case will require evaluation in light of applicable FERC tariffs. PG&E cautions that differences in taxation between investor-owned and public utilities should be considered in the design of any tax credits or other legislative subsidies to advance certain favored types of DG.

4.B.3.5 SYSTEM INTEGRITY

The utilities caution that if DG penetration reaches significant levels, potential adverse system impacts will need to be addressed; chiefly including system integrity, safety and reliability. They say that engineering standards are the primary means by which utilities maintain system integrity, safety and reliability in a cost-effective manner and interconnection standards are the key to integrating DG with no adverse system impacts. The utilities do not foresee that system integrity will be a big issue with DG. Utilities report few, if any, significant problems related to customer generators negatively impacting the T&D system. Citing concerns about potential problems such as those caused by weather related and other system outages, however, the utilities propose that system maintenance should remain under active review and management by a single, responsible authority (that is, by the LDC).

4.B.3.6 RELIABILITY IMPACTS

The utilities foresee that DG will enhance system reliability if used by the utility for peak clipping. Customers clearly can enhance their own reliability with DG, but SCE claims that distribution system operator control over redundant resources is essential to maintain and possibly even increase system reliability. SCE says this requires that "both customer-site and on-grid DG are safely integrated with the utility's system," and they assert that a smaller distribution operator cannot provide such system reliability benefits.

4.B.3.7 SAFETY ISSUES

Utilities are unanimous in their position that implementation and operation of DG should not result in "islanding". By that, they mean a situation in which, due to an outage or a disturbance, a self-contained area of generation and load becomes separated from the rest of the utility system. This is a safety issue because utility workers must be certain whether or not a circuit is energized before they work to restore the system. The utilities maintain this is another reason why utilities should have operational control over DG.

It should be noted that safety and reliability concerns inherently conflict because of the ability of DG systems to operate in this islanded manner. If DG systems are permitted to operate in island fashion during outages caused by failures elsewhere, then customers inside the island can benefit from increased reliability, less frequent and shorter duration outages, and DG owners may seek compensation for providing it. In some circumstances, islanded DG systems can even contribute to faster restoration of the rest of the system. On the other hand, if islanding is prohibited, then the reliability benefits will be lost. That is why DG proponents request interconnection standards that allow for islanding while assuring safety via less restrictive means. (See sections 2.B.2 and 2.B.3.)

The utilities say that by its very nature DG introduces additional complexity into the distribution system, and therefore the need for more sophisticated protection systems. Also, the utilities propose that interconnection and operating standards must address the impacts DG could have on other customers on the feeder.

4.B.3.8 ENVIRONMENTAL IMPACTS

The utilities observe that characterizing environmental impacts from DG is difficult, given the many available technologies, rapid rates of technological change and development, and uncertain rates of market penetration. They point out there is some uncertainty about applying environmental regulations to large numbers of small, widely dispersed, sources. They suggest that DG will raise a variety of environmental concerns, involving construction, noise, visual impacts, land use and zoning. For example, SPP offers its opinion that, from an aesthetic perspective, "siting DG in environmentally sensitive areas such as the Lake Tahoe Basin would be a less attractive option than importing power into the basin on existing or modified transmission and distribution facilities."

The utilities do recognize air pollution as a potentially serious concern, while noting that DG technologies vary greatly in emissions; compared to one another and to central generation. They express concern about possible adverse local environmental impacts because DG typically is located at or near load centers, where more people are, and employs relatively short exhaust stacks that disperse emissions near ground level. At the same time, however, it should be noted that the net effects of DG are of greatest general importance. Frequently, waste heat produced by DG systems will serve some useful purpose at or very near the site, thus raising system fuel efficiency and reducing net environmental impacts as compared to central station generation combined with separate, on-site heat producing systems.

4.B.3.9 FUEL/NATURAL GAS SUPPLY

If DG systems that use natural gas fuel are installed in great numbers, utilities assert there will be substantial implications for the natural gas delivery infrastructure. They do suggest that increased use of the existing natural gas distribution infrastructure could help lower gas unit distribution costs, however. They note that planning and capital cost estimates are important, but also raise public health and safety concerns that will arise if gas delivery is curtailed (e.g., under winter peaking conditions). The utilities say that gas transportation charges for DG can be addressed within the current regulatory framework.

The utilities propose that gas used to fire DG should be classified as non-core and interruptible during periods of high residential gas use, the same as for other electrical facilities that use gas. A countervailing point of view, however, is that many natural gas fired DG systems will be high efficiency cogenerators and one of the specific attractions for early adopters of DG technologies is very high reliability. Therefore, it would be shortsighted and create a very significant market barrier to arbitrarily classify all DG use as interruptible.

4.B.3.10 WIRES BYPASS AND STANDBY CHARGES

The utilities feel that DG can result in bypass of wires service and the stranding of distribution assets, both substation and wires. For example, PG&E asks the CPUC to provide "adequate means for utilities to recover past investments in distribution facilities to the extent that these investments become stranded" by customer-sited DG. Standby requirements will depend to some degree on whether DG has "black start" capability or uses induction technologies, but the primary concern is that customers who self-generate, yet depend on the grid for backup, should pay their fair share of the fixed costs of providing distribution service in order to avoid shifting costs to other customers. In the long run, some shifting of distribution charges (to increase fixed and decrease variable costs) might be warranted for DG customers in specific, and perhaps for all customers.[16]

4.B.3.11 INTERCONNECTION STANDARDS

The utilities say they will still have the lion's share of the responsibility for maintaining safe and reliable operation of the distribution system. Therefore, they underscore their beliefs that interconnection standards and practices will be of utmost importance, and state that while they "should be made as simple and predictable as possible" [PG&E], they should conform to "best practices" and the safety, integrity and reliability of the system must be preserved. The utilities predict that as DG proliferates, so will the complexity of standards. The utilities say that customers with DG must take on increased responsibility commensurate with their changed role, and advise that new building codes, installation oversight, and consumer protection programs may be necessary.

4.B.3.12 SOCIAL, ECONOMIC AND LABOR IMPACTS

Utilities agree that both utility and customer use of DG can help to lower energy costs, positively benefiting all customers. They predict that businesses can employ DG to lower their costs without cutting jobs, and thereby improve California's competitiveness over other regions. The utilities believe positive employment impacts will result from local tradesmen installing and maintaining DG, although they claim these may be offset by a corresponding loss of jobs in the UDC.

It should be noted that there is a substantial literature on economic and employment effects of various energy technologies that strongly suggests DG will have a positive effect on both the economy and employment.[17] The general finding of this kind of research is that central station electric generation is one of the most capital intensive and least labor intensive activities in the U.S. economy. Because smaller systems lead to economies in the manufacturing of generators, rather than economies in construction, DG affects the economy similar to other hard-goods manufacturing industries and produces more jobs per unit of output.

Again, with respect to social impacts the utilities repeat their assertion that DG can create negative effects on local air quality, noise and aesthetics.

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[16] Rate design which best accommodate DR is the subject of a NARUC companion paper. See note 12 on page 3-3.

[17] See, for example, Geller, DeCicco, & Laitner (1992), ***Energy Efficiency and Job Creation***, Washington, DC: American Council for an Energy Efficient Economy, http://www.aceee.org/pubs/ed922.htm.

The utilities note that public purpose programs that are funded through electric rates can be negatively impacted by decreased use of the distribution system, although to the extent DG is fueled by natural gas this effect could be mitigated by the public purpose component of natural gas rates.

4.B.4 EXIT FEES OR COMPETITIVE TRANSITION CHARGES

In several states, discussion about DG policies has focused on the possible allocation of exit fees. A load could be subject to a surcharge known as a “competitive transition charge” or "exit fee" that would be paid to the LDC if an existing load is served by any party other than the LDC. Generally speaking, the logic behind this concept is that customers might otherwise avoid paying their share of the costs for the existing utility infrastructure by switching to self-generation. On the other hand, this type of system bypass has always been available to customers without the imposition of exit fees, and state legislation may not allow it.

California currently does not impose CTC charges on loads served by self-generation that are new or incremental loads. California Assembly Bill 1890, defines transition costs as "costs for facilities rendered uneconomic by the transition to a deregulated, competitive electric structure." The bill establishes a mechanism for recovery of those costs by assessing them to customers, subject to “changes in usage” (Section 371). Changes in usage are defined as those “occurring in the normal course of business” (e.g., changing or reducing business operations, leaving the service territory, increasing efficiency of cogeneration equipment, demand-side management, or energy efficiency, and “fuel switching *including fuel cells*”) [emphasis added]. In Section 383, responsibility is given to the California Energy Resources Conservation and Development Commission to determine whether fuel cells should be treated as fuel switching for the application of CTCs.

In Arizona, CTC’s are not imposed on self-generation facilities even when the loads were formerly served by the utility. The Arizona Corporation Commission Rule 14-2-1607 provides:

> Any reduction in electricity purchases from affected utility resulting from self-generation, demand side management, or other demand reduction attributable to any cause other than the retail access provisions of this Article shall not be used to calculate or recover any Stranded Cost from a consumer.

The New Jersey legislation, adopted January 7, 1999, determines that on-site generators that sell only to on-site loads are exempt from paying exit fees. However, the legislation goes on to state that on-site generation will be subject to all exit fees if “the amount of generation from on-site generators has reduced the kilowatt hours distributed by an electric public utility to a level equal to 92.5 percent of the 1999 kilowatt hours distributed."

The NJ legislation encourages the limited adoption of DG. It opens the door to substantial market penetration by allowing DG installations to occur without cumbersome and expensive standby, exit and stranded generation fees. The upper limit appears generous for now, but is arbitrary. It is not clear what will happen if and when the limit is exceeded.

4.B.5 ADMINISTRATION BILL

4.B.5.1 ACCELERATED DEPRECIATION

The Clinton Administration has proposed the Comprehensive Electricity Competition Act. It includes a provision for accelerated depreciation for "distributed power property," to 15 years.

Such "distributed power property" is fairly broadly defined as:

- any DG installed at a commercial, industrial or rental property, or
- any combined heat (or cooling) and power (greater than 40% useful energy output, on a Btu basis) installations at an industrial site, with an on-site aggregated rating of over 500 kW.

A 50% maximum limitation is placed on the fraction of the electricity created which can be used by "unrelated persons," presumably including neighboring electricity consumers. Other than the 500 kW minimum for combined heat and power (CHP) systems, these rules and limitations should not cause any concern to anyone wishing to take advantage of the accelerated depreciation. Owner-occupied residential installations would apparently be ineligible.

4.B.5.2 TAX CREDIT FOR CHP INSTALLATIONS

These provisions would add CHP to the technologies which are allowed a tax credit in the year of their installation (only for calendar years 2000, 2001 and 2002, in the current version of the legislation). The CHP tax credit would be 8%, and for solar and geothermal 10%, of the allowable installed costs.

Performance and quality standards of each installation are to be prescribed by several agencies, including DOE and EPA. A 50 kW minimum size and a 60% minimum system energy efficiency (on a Btu basis) would be required. Very large distributed units (> 50 MW) would have to be over 70% efficient. A broad range of thermal and electrical energy outputs would be allowed.

4.B.5.3 NET METERING

The Administration Bill also includes provisions for net metering. Net metering (sometimes called net billing) provisions allow customers to generate electricity on-site to serve their own loads and sell any excess to their LDC at or near the retail price. Until the recent past, net metering often meant using a single standard electric meter which would track the customers' electric usage from the utility and literally spin the meter backwards when the customer sent excess electricity back into the utility grid; offsetting their prior usage. Newer metering technologies are capable of separately tracking both usage and sales, and some even track these by time of day.

So far, 30 states have adopted net metering for some or all electric utilities. Net metering policies vary significantly among the states, in terms of: (a) eligibility by customer class, system and fuel types, and sizes; (b) maximum numbers of customers or kW allowed, by utility or statewide; and (c) treatment of net excess generation (NEG). NEG means generation exceeding consumption during a billing period. States with provisions most favorable to DG generally allow net metering for the broadest array of system types (often renewables and cogeneration, including fuel cells), for all customer classes, for systems up to 100 kW, with NEG purchased by the utility at the customer's retail rate. In many states, NEG is purchased by the utility at an avoided cost rate, less than retail. At the other end of the spectrum, many states allow net metering only for solar or solar and wind systems, perhaps for residential customers only, in sizes up to 10 kW, and with NEG donated to the utility. Roughly one third of the states with net metering fall at each end of this spectrum, and the other third falls somewhere in the middle.

In Texas, net metering is not employed because it is perceived as an artifact of the monopoly utility structure, where there existed a particular sort of relationship between an integrated utility company and each customer. Texas decided that net metering was not compatible with open retail competition, and provided that excess generation from DG systems can be sold into competitive markets; to end-use customers, energy service companies, retail electric providers, and power generation companies.

SECTION 5
NEXT STEPS

The major impetus for expanding DG installations is the promise of potential economic savings and reliability benefits that could come from either utilities or customers providing more supply nearer to loads. This report summarizes pertinent existing literature about DG interconnection and associated tariff and contract provisions. It also attempts to draw out conclusions and recommendations about provisions that can be employed in order to minimize barriers to the implementation of cost-effective DG.

The Interconnection Provisions reported here are intended to serve as a general framework, and not as a purely technical or complete specification that will serve in all cases: Different circumstances may call for specific technical requirements. Still, state utility regulators may significantly reduce areas of potential confusion and conflict by establishing general provisions and describing the process by which remaining details are to be worked out.

Public policies, when stated, have been generally favorable to DG. But, they have often been vague, too, about how to encourage DG. In the early stages, most industry restructuring policy discussions have practically ignored DG, leaving it as a topic to be addressed later, if at all. California is one exception, where the possibilities of DG have been brought to the fore by CADER broad questions about DG policy are being addressed in the OIR. This includes questioning even whether distribution monopolies will still be needed in a competitively restructured electric utility industry. Texas is another exception, where restructuring legislation and PUC policies have clearly favored DG development and established the principle that customers have a right to both utilize DG and integrate DG systems into the utility grid.

Since the market penetration of DG to date has been quite limited, many of the tariff issues have yet to be addressed in a uniform manner (again, with the exception of Texas). Instead, many jurisdictions are still addressing DG tariff issues on a case-by-case basis, often involving conflicts between utilities and the customers who wish to interconnect.

Outside of Texas, the technical provisions have been the locus of the most concrete recent progress in DG interconnection policies. Several states have held extensive hearings and reached limited conclusions, at least for interim procedures to be applied to certain technologies and sizes. Meanwhile, the IEEE SCC 21 process, to develop a national consensus technical interconnection standard for DG should be supported. That process is accelerating efforts to resolve the technical DG interconnection issues. It promises to avoid redundant and conflicting work which might otherwise result, if states are pressured to develop their own technical standards.

For customers to take advantage of DG will require installations that proceed without undue costs, in a straightforward manner, in a reasonable length of time. But, DG installations must not result in any detriment to the safety and security of the local wires system. Technical interconnection issues are advancing quickly towards meeting those goals, but more attention is needed to resolve, equitably, the many non-technical and process issues that will govern relationships between LDC's, customers, and independent DG owner/operators.

Customers are expected to continue to pay standard rates for services used during any periods of negotiations, and they are often obligated to pay for required distribution system upgrades. In addition, customers may face non-negotiable exit fees, standby charges, study fees, and the like. In many circumstances, if a customer installs and properly operates a DG unit substantial utility benefits will result. Currently, however, neither customers, DG providers, or state regulators have access to the information needed to determine where and when DG units would generate such benefits, let alone to quantify them. In most states, only LDC's have access to such data, if it is available at all. And, most states lack approved methodologies and regulatory mechanisms to identify and quantify such benefits and then allocate them between DG owners and utilities.

In some states, substantial attention has been devoted to deciding whether distribution utilities should be allowed to own and/or operate their own DR. That attention may have detracted, however, from classifying and quantifying the potential benefits of DR, and then developing sound policies to achieve and allocate them. This type of decision should be reached only after careful deliberation, though, because a blanket prohibition against LDC deployment of DR might unintentionally prevent utilization of many combinations of generation, demand-management, and storage resources that might otherwise be among the most economical means for providing distribution services.

On the tariff side, net metering has been an important initiative, but it often applies only to small renewable energy and fuel cell units, and under modest capacity limits by utility territory or state. Thus, net metering may be a good start towards tariffs that are fair to DG, but the early experience with it needs to be evaluated. If it can be shown that net metering successfully encourages cost effective DG installations without creating undue cross subsidies or harming LDC shareholders, then expanded eligibility should be considered for commercial and industrial customers, using somewhat larger system sizes, and other clean technologies including combined heat and power, electric and thermal storage, fuel cells, etc. On the other hand, some different sharing of costs and benefits may be called for if significant expansion is to take place under the umbrella of net metering. It should be remembered, however, that the net metering model was developed within the context of the vertically integrated monopoly utility structure. It may not be appropriate, in the long run, for a restructured industry with full retail competition.

It is clear that contractual relationships between regulated distribution utilities and DG owners and operators will become increasingly important as the restructuring of the electric utility industry continues. A logical next step for NARUC is to expand on the work of this report by developing suggested Model Rules for the full range of non-technical DG interconnection and contractual policies.

APPENDIX A -- DEFINITIONS

- CBEMA curve – A published curve that displays a recommended guideline for voltage capabilities of electronic equipment.
- Closed transition - A means of switching the power supply to a given load between two different sources of supply, so that both sources operate in parallel for only the short period of time needed for the switching to take place. This method of switching generation to the load (from the utility to a DG) should assure that power to the load is not lost due to the switching action.
- Disconnect – A switching device that completely isolates one electric circuit from another.
- Distributed generation (DG) – Small sources of electric power that are connected to the electric utility's distribution system.
- Distribution utility – The utility company (or portions of a utility company) that provides the delivery service, at distribution voltages. This is sometimes called a "wires company" or local distribution company (LDC).
- Electric storage – Devices designed to store electricity for a period of time, such as batteries or flywheels.
- Event recorder – A device that records the state of the electric system just before an event and for a period of time afterwards. Event recorders are usually triggered by events such as short circuits or low voltage.
- Flicker – Voltage variations on a distribution system caused by switching, load changes, or other transient disturbances. Flicker may cause problems with electronic equipment.
- Flywheel – A device for storing electricity using the inertia of a fast-spinning mass. Electricity that is stored in a flywheel can be retrieved very quickly on command.
- Fuel cell – A device that converts a fuel source to electricity, chemically. Fuel cells have no moving parts.
- Gas turbine – An electric generator using natural gas (or another, similar gas product) as a fuel source. Gas turbines generally range in size from a few hundred kilowatts to a few hundred megawatts. (See also Microturbine.)
- Geothermal energy – Heat generated within the earth's crust, due to geological processes. Electricity can be generated, in some locations, using steam generated by geothermal energy.

- Harmonics - Voltages and currents of frequencies that are multiples of 60 Hertz. Excessive harmonics can cause problems with electronic equipment, especially protection systems, as well as overheating of equipment. In some cases high voltages and large currents may be caused by harmonics.
- IEEE – Institute of Electrical and Electronic Engineers. The IEEE often establishes standards and guidelines for many technical matters, employing committees and working groups composed of knowledgeable volunteers.
- IEEE 519 – A standard pertaining to allowable harmonic voltages and currents on a power distribution system.
- IEEE SCC21 – Standards being developed now, related to the interconnection of DG.
- Induction generator – A rotating electromechanical generator that is not synchronized to the power system. It will generate power at a voltage and frequency as established by the power system, not the generator.
- Inverter – An electronic device that converts electricity from DC into AC.
- Islanded system – A part of the distribution system that is separated from the rest of the power grid. An islanded system, in the context of this paper, would have DG as its only source of generation.
- Isolation transformer – A means for electrically isolating one part of the distribution system from another. There is no electrical connection across an isolation transformer, only a magnetic connection.
- Microturbine – A very small gas turbine, typically less than 200 kilowatts.
- One-line diagram – A simple schematic diagram of an electric distribution system, using a single line to depict the three phases and associated controls, monitoring and protection.
- Open transition - A means of connecting a DG to its load where the utility circuit and generator are never in parallel. This method of switching loads from utility to generator results in a loss of power to the load for the very short period of time needed to switch from one generating source to another.
- Parallel operation – The utility and the source of DG are operating so that each is capable of serving the same loads at the same time.
- Photovoltaic – Electric energy from solar cells, which directly convert sunlight into electricity. Photovoltaic cells produce DC electricity, and typically connect to the electric distribution system using an inverter.
- Physical isolation – A means of assuring that parts of an electric distribution system are not connected to one another by any conductors.
- Protection systems – Electronic and/or electromechanical devices that open circuit breakers to avert problems due to short circuits, overloads and other

functions, which could interrupt electric service and/or damage electric distribution system equipment .

- Provider – The owner and/or operator of the generation equipment. The provider has responsibility for the generation equipment.
- Real time data – Data that can be acquired nearly instantly, with a delay no longer than a few seconds.
- Reclosing – After a distribution circuit opens and trips off-line, it can reclose and restore service. Reclosing can be instantaneous or with some time delay.
- Resonant over-voltage – A phenomenon that causes higher than normal voltages on ungrounded distribution systems. These voltages sometimes can reach as much as 5 to 10 times the normal line to ground voltage.
- Supervisory control and data acquisition (SCADA) – A system that remotely controls and obtains data from devices such as circuit breakers and switches.
- Stiffness (of the distribution system) – A measure of how well the distribution system resists change due to loads or other connections. A "stiff" system is the opposite of a "weak" system. The greater the short-circuit MVA, the stiffer the system. The stiffer the system, the less effect DG has on it.
- Synchronize (also, synchronization) – To make sure that the synchronous source of generation and the distribution system are in phase before they are electrically connected together. Failure to synchronize the two systems may result in extensive damage to facilities and cause injury to personnel.
- Synchronous generator (also, synchronous source of power) – A source of generation (power) that does not need to be connected to other generation in order to provide consistent voltage and energy to a load.
- Switching, clearance and tagging procedures – Safety procedures used by electric utilities to ensure that switching devices do not operate unless and until appropriate preconditions are met and verified.
- Telemetry – Electronic equipment for remote data reading and transmission.
- Total harmonic distortion (THD) – A measure, expressed in percent, of the distortion of the current or voltage sine wave present on a power system, caused by all harmonics of the fundamental frequency (60 Hertz).
- Transfer trip – A signal from one location (such as a recloser) typically sent to trip a remote circuit breaker under certain system short circuit conditions.
- VAR support – The requirement for a certain level of reactive volt-amperes in order to provide certain system power factor and/or voltage level.
- Zero sequence current – Current that flows through all three phases of a circuit as well as through the ground return. Commonly known as ground fault current.